**Appendix F.1.**
**Point Source Emissions Inventory Documentation**

**TABLE OF CONTENTS**

## LIST OF TABLES

# POINT SOURCE EMISSIONS INVENTORY DOCUMENTATION

## I. INTRODUCTION

The attainment modeling for the Charlotte-Gastonia-Rock Hill, North Carolina-South Carolina 8-hour ozone nonattainment area (referred to as the Metrolina area) was performed in conjunction with the regional haze modeling being done by the Southeast Regional Planning Organization, Visibility Improvement State and Tribal Association of the Southeast (VISTAS) and the fine particulate matter (PM2.5) and ozone modeling being done by the Association of Southeastern Integrated Planning (ASIP). VISTAS and ASIP are run by the ten Southeast states (Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee, Virginia and West Virginia). Since the regional haze and PM2.5 modeling uses annual simulations and includes an intermediate year that is the attainment year required for the Metrolina nonattainment area, the South Carolina Department of Health and Environmental Control (SCDHEC) decided to use this modeling for its attainment demonstration.
Although the VISTAS/ASIP developed emission estimates for all pollutants of concern for regional haze, fine particulate matter and ozone, only the emissions inventory discussions relevant to ozone formation, i.e., nitrogen oxides ($NO_x$) and volatile organic compounds (VOCs), will be discussed in this document. The other pollutants will be discussed in detail in the regional haze and fine particulate matter State Implementation Plans (SIPs).

## II. 2002 POINT SOURCE INVENTORY DEVELOPMENT

This section details the development of the 2002 base year inventory for point sources. There were two major components to the development of the point source sector of the inventory. The first component was the incorporation of data submitted by State and Local (S/L) agencies to the United States Environmental Protection Agency (USEPA) as part of the Consolidated Emissions Reporting Rule (CERR) requirements. Work on incorporating the CERR data into the revised base year involved: 1) obtaining the data from the USEPA or the S/L agencies, 2) evaluating the emissions and pollutants reported in the CERR submittals, 3) augmenting CERR data with annual emission estimates for primary coarse particulate matter (PM10-PRI) and PM2.5-PRI; 4) evaluating the emissions from electric generating units, 5) completing quality assurance reviews for each component of the point source inventory, and 6) updating the database with corrections or new information from S/L agencies based on their review of the 2002 inventory. This document will not address the augmenting of the particulate matter since these pollutants are not considered an ozone precursor. The remaining processes used to perform the emission inventory development are described in the first portion of this section.

The second component was the development of a "typical" year inventory for electric generating units (EGUs). The VISTAS/ASIP states determined that a typical year EGU inventory was necessary to smooth out any anomalies in emissions from the EGU sector due to meteorology, economic, and outage factors in 2002. This is consistent with the USEPA's guidance for SIP modeling. The typical year EGU inventory is intended to represent the five-year (2000 2004) period that will be used for the attainment demonstration for the PM2.5 and ozone SIPs, and to determine the regional haze reasonable progress goals. The second part of this section discusses the development of the typical year EGU inventory.

### A. Development of 2002 Actual Point Source Inventory

VISTAS/ASIP contracted with MACTEC to develop the 2002 emission inventory. SCDHEC submitted the most updated statewide emissions inventory to the contractor. Once all of the files were obtained, MACTEC ran the files through the USEPA's National Emissions Inventory (NEI) Input Format (NIF) Basic Format and Content checking tool to ensure that the files were submitted in standard NIF format and that there were no referential integrity issues with those files.

The primary task in preparing the 2002 base year inventory was the incorporation of corrections and new information as submitted by the S/L agencies based on their review of the previous draft versions of the inventory. The following subsections document the data sources for the inventory, the checks made on the CERR submittals, the evaluation of EGU emissions, and other quality assurance/quality control (QA/QC) checks. The final subsection summarizes the 2002 $NO_x$ and VOC inventory by sector (EGU and non-EGU).

Throughout the development of the point source emissions inventory, the SCDHEC completed detailed reviews of the inventories prepared by the VISTAS/ASIP contractor and provided comments and data corrections when needed.

### 1. Consolidated Emissions Reporting Rule

The CERR was published in the Federal Register on Monday, June 10, 2002 (FR Volume 67, Number 111, pp 39602 - 39616). This brief summary is provided as a quick introduction to the CERR and covers the major items in the rule.

The purpose of the CERR is to simplify reporting, offer options for data collection and exchange, and unify reporting dates for various categories of criteria pollutant emission inventories. The rule applies to S/L agencies. Previous reporting requirements have, at times, forced reporting agencies into inefficient collecting and reporting activities. This rule consolidates the emission inventory reporting requirements found in various parts of the Clean Air Act (CAA). Consolidation of reporting requirements will enable S/L agencies to better explain to program managers and the public the necessity for a consistent inventory program, increase the efficiency of the emission inventory program, and provide more consistent and uniform data.

States are required to prepare a comprehensive statewide inventory every three years. The first inventory was for the year 2002 and was due June 1, 2004. This CERR inventory was used for the VISTAS/ASIP 2002 base year.

### 2. EGU Analysis

MACTEC made a comparison of the annual sulfur dioxide ($SO_2$) and $NO_x$ emissions for EGUs as reported in the S/L agencies CERR submittals and the data from the USEPA's Clean Air Markets Division (CAMD) continuous emission monitoring (CEM) database to identify any outstanding discrepancies. Facilities report hourly CEM data to the USEPA for units that are subject to CEM reporting requirements of the $NO_x$ SIP Call rule and Title IV of the CAA. The USEPA sums the hourly CEM emissions to the annual level, and MACTEC compared these annual CEM emissions to those in the S/L inventories. The 2002 CEM inventory containing $NO_x$ and $SO_2$ emissions and heat input data were downloaded from the USEPA CAMD web site (www.epa.gov/airmarkets). The data were provided by quarter and emission unit.

The first step in the EGU analysis involved preparing a crosswalk file to match facilities and units in the CAMD inventory to facilities and units in the S/L inventories. In the CAMD inventory, the Office of Regulatory Information Systems (ORIS) identification (ID) code identifies unique facilities and the unit ID identifies unique boilers and internal combustion engines (i.e., turbines and reciprocating engines). In the South Carolina point source emissions inventories, the State and county code (FIPS code) and State facility ID together identify unique facilities and the emission unit ID identifies unique boilers or internal combustion engines. In most cases, there is a one-to-one correspondence between the CAMD identifiers and the S/L identifiers. However, in some of the S/L inventories, the emissions for multiple emission units are summed and reported under one emission unit ID. MACTEC created an Excel spreadsheet that contained an initial crosswalk with the ORIS ID and unit ID in the CEM inventory matched to the State and county FIPS, State facility ID, and emission unit ID in the emissions inventories. The initial crosswalk contained both the annual emissions summed from the CAMD database, as well as the S/L emission estimate. The matching at the facility level was nearly complete. In some cases, however, S/L agencies or stakeholders' assistance was needed to match some of the CEM units to emission units in the S/L inventories.

The second step in the EGU analysis was to prepare an Excel spreadsheet that compared the annual emissions from the hourly CAMD inventory to the annual emissions reported in the S/L inventory. The facility-level comparison of CEM to emission inventory $NO_x$ and $SO_2$ emissions found that for most facilities, the annual emissions from the S/L inventory equaled the CAMD CEM emissions. Minor differences could be explained because the facility in the S/L inventory contained additional small or emergency units that were not included in the CAMD database.

The final step in the EGU analysis was to compare the $SO_2$ and $NO_x$ emissions for select Southern Company units in the VISTAS/ASIP region. Southern Company is a super-regional company that owns EGUs in four VISTAS/ASIP States – Alabama, Florida, Georgia, and Mississippi – and participates in VISTAS as an industry stakeholder. Southern Company independently provided emission estimates for 2002 as part of the development of the preliminary VISTAS 2002 inventory. Emission estimates were reviewed by the States and incorporated into the States CERR submittal. There were no major inconsistencies between the Southern Company data, the CAMD data, and the S/L CERR data.

The minor inconsistencies found included small differences in emission estimates (<2 percent difference), exclusion/inclusion of small gas-fired units in the different databases, and grouping of emission units in S/L CERR submittals where CAMD listed each unit individually. MACTEC compared $SO_2$ and $NO_x$ emissions on a unit-by-unit basis and did not find any major inconsistencies.

### 3. Summary of the 2002 Actual Inventory

Table F1-1 summarizes the final 2002 actual base year inventory for South Carolina. All values are in tons per year. The EGU emissions include the emissions from all processes with a Source Classification Code (SCC) of either 1-01-xxx-xx (External Combustion Boilers - Electric Generation) or 2-01-xxx-xx (Internal Combustion Engines - Electric Generation). Emissions for all other SCCs are included in the non-EGU column.

**Table F1-1:**
**2002 Actual Point Source Inventory for South Carolina**

| State | All Point Sources | EGUs | Non-EGUs |
|---|---|---|---|
| $SO_2$ | 259,916 | 206,399 | 53,518 |
| $NO_x$ | 130,394 | 88,241 | 42,153 |
| VOC | 38,927 | 470 | 38,458 |
| CO | 63,305 | 6,990 | 56,315 |
| PM10-PRI | 35,542 | 21,400 | 14,142 |
| PM2.5-PRI | 27,399 | 17,154 | 10,245 |
| NH3 | 1,553 | 142 | 1,411 |

## B. Development of Typical Year EGU Inventory

VISTAS/ASIP developed a typical year 2002 emission inventory for EGUs to avoid anomalies in emissions due to variability in meteorology, economic, and outage factors in 2002. The typical year inventory represents the five year (2000-2004) period, which are the years used to calculate the average design value.

Data from the USEPA's CAMD were used to develop normalization factors for producing a 2002 typical year inventory for EGUs. The VISTAS/ASIP contractor used the ratio of the 2000 2004 average heat input and the 2002 actual heat input to normalize the 2002 actual emissions. MACTEC obtained data from the USEPA CAMD for utilities regulated by the Acid Rain program. Annual data for the period 2000 to 2004 were obtained from the CAMD web site. The parameters available were the $SO_2$ and $NO_x$ emission rates, heat input, and operating hours.

MACTEC used the actual 2002 heat input and the average heat input for the 5-year period from 2000-2004 as the normalization factor, as follows:

$$\text{Normalization Factor:} \quad \frac{\text{2000-2004 average heat input}}{\text{2002 actual heat input}}$$

If the unit did not operate for all five years, then the 2000-2004 average heat input was calculated for the one or two years in which the unit did operate. The annual actual emissions were multiplied by the normalization factor to determine the typical emissions for 2002, as follows:

Typical Emissions = 2002 actual emissions x Normalization Factor

After applying the normalization factor, some adjustments were needed for special circumstances. For example, a unit may not have operated in 2002 and thus have zero emissions. If the unit had been permanently retired prior to 2002, then MACTEC used zero emissions for the typical year. If the unit had not been permanently retired and would normally operate in a typical year, then MACTEC used the 2001 (or 2000) heat input and emission rate to calculate the typical year emissions.

The final step was to replace the 2002 actual emissions with the 2002 typical year data described above. MACTEC provided the raw data and results of the typical year calculations in a spreadsheet for S/L agency to review and comment. Any comments made were incorporated into the typical 2002 inventory.

Table F1-2 summarizes emissions by state and pollutant for the actual 2002 EGU inventory and the typical year EGU inventory. For the entire VISTAS region, actual 2002 $NO_x$ emissions were about 0.1 percent lower than the typical year emissions. South Carolina's actual 2002 $NO_x$ emissions were 0.3 percent lower than the typical year emissions.

**Table F1-2**
**$NO_x$ Emissions Comparison for EGUs**

| | $NO_x$ Emissions (tons/year) | | |
|---|---|---|---|
| State | Actual 2002 | Typical 2002 | Percentage Difference |

| | | | |
|---|---|---|---|
| AL | 161,038 | 154,704 | 3.9 |
| FL | 257,677 | 282,507 | -9.6 |
| GA | 147,517 | 148,126 | -0.4 |
| KY | 198,817 | 201,928 | -1.6 |
| MS | 43,135 | 40,433 | 6.3 |
| NC | 151,854 | 148,812 | 2.0 |
| SC | 88,241 | 88,528 | -0.3 |
| TN | 157,307 | 152,137 | 3.3 |
| VA | 86,886 | 85,081 | 2.1 |
| WV | 230,977 | 222,437 | 3.7 |

## III. 2009 POINT SOURCE EMISSIONS INVENTORY DEVELOPMENT

Different approaches were used for different sectors of the point source inventory. For the EGUs, VISTAS/ASIP relied primarily on the Integrated Planning Model® (IPM) to project future generation, as well as to calculate the impact of future emission control programs. The IPM results were adjusted based on S/L agency knowledge of planned emission controls at specific EGUs. For non-EGUs, VISTAS/ASIP used recently updated growth and control data consistent with the data used in the USEPA's Clean Air Interstate Rule (CAIR) analyses, and supplemented these data with available S/L agency input and updated fuel use forecast data for the United States Department of Energy.

For both sectors, VISTAS/ASIP generated 2009 inventory with control scenarios that account for post-2002 emission reductions from promulgated and proposed federal, State, local, and site-specific control programs as of July 1, 2004. Section 3.1 discusses the EGU projection inventory development, while Section 3.2 discusses the non-EGU projection inventory development.

### A. EGU Emission Projections

The following subsections discuss the aspects of the development of the EGU projections.

- A chronology of the EGU development process used by MACTEC and key decisions in selecting the final methods for performing the emissions projections.

- The development of the final set of IPM runs that are included in the VISTAS/ASIP 2009 inventory.

- The process of transforming the IPM parsed files into NIF format.

- The process for ensuring that units accounted for in IPM were not double-counted in the non-EGU inventory.

- The QA/QC checks that were made to ensure that the IPM results were properly incorporated into the VISTAS/ASIP inventory.

- The changes to the IPM results that S/L agencies requested be included in the ( inventory based on new information that was not accounted for in the IPM runs.

- Summary of 2002 and 2009 EGU emissions by state for $NO_x$ and VOC

### 1. Chronology of the Development of EGU Projections

Initially, VISTAS/ASIP considered three options for developing the 2009 projection inventory for EGUs:

- Option 1 – Use the results of IPM modeling conducted in support of the proposed CAIR base and control case analyses as the starting point and refine the projections with readily available inputs from stakeholders. These IPM runs were conducted for 2010, which VISTAS would use to represent projected emissions in 2009.

- Option 2 – Use the VISTAS/ASIP 2002 typical year as the starting point, apply growth factors from the Energy Information Administration, and refine future emission rates with stakeholder input regarding utilization rates, capacity, retirements, and new unit information.

- Option 3 – Use the results of a new round of IPM modeling sponsored by VISTAS and the Midwest Regional Planning Organization (MRPO). These runs incorporated VISTAS specific unit and regulation modified parameters, and generate results for 2009 explicitly.

An additional consideration for each of the three options was the inclusion of emission projections developed by the Southern Company specifically for their units. Southern Company is a super-regional company that owns EGUs in Alabama, Florida, Georgia, and Mississippi and participates in VISTAS as an industry stakeholder. Southern Company used their energy budget forecast to project net generation and heat input for every existing and future Southern Company EGU for the year 2009. Further documentation of how Southern Company generated the 2009 inventory for their units can be found in Developing Southern Company Emissions and Flue Gas Characteristics for VISTAS Regional Haze Modeling (April 2005, presented at 14th International Emission Inventory Conference).

Each of these three options and the Southern Company projections were discussed in a series of conference calls with the VISTAS EGU Special Interest Work Group (SIWG) during the fall of 2004. During a conference call on December 6, 2004, the VISTAS EGU SIWG approved the use of the latest VISTAS/MRPO sponsored IPM runs (Option 3) to represent 2009 EGU forecasts of emissions the future year cases.

The Option 3 IPM modeling resulted from a joint agreement by VISTAS and MRPO to work together to develop future year utility emissions based on IPM modeling. The decision to use IPM modeling was based in part on a study of utility forecast methods by E.H. Pechan and Associates, Inc. (Pechan) for MRPO, which recommended IPM as a viable methodology (see Electricity Generating Unit {EGU} Growth Modeling Method Task 2 Evaluation, February 11, 2004). Although the USEPA used IPM recently to support their rulemaking for the CAIR, VISTAS stakeholders felt that certain model inputs needed to be improved. Thus, VISTAS and MRPO decided to hire contractors to conduct new IPM modeling and to post-process the IPM results. Southern Company projections in 2009 were roughly comparable with IPM.

In August 2004, VISTAS/ASIP contracted with ICF to run IPM to provide utility forecasts for 2009 under two future scenarios – Base Case and CAIR Case. The Base Case represents the current operation of the power system under currently known laws and regulations, including those that come into force in the study horizon. The CAIR Case is the Base Case with the proposed CAIR rule superimposed. The run results were parsed at the unit level for 2009. The IPM output files were delivered by ICF in November, and the post-processed data files were delivered by Pechan in December 2004. Only the CAIR case was used in the final 2009 modeling.

On March 10, 2005, the USEPA issued the final CAIR. VISTAS and MRPO, in conjunction with other RPOs, conducted another round of IPM modeling, which reflected changes to control assumptions based on the final CAIR as well as additional changes to model inputs based on S/L agency and stakeholder comments. Several conference calls were conducted in the spring/summer of 2005 to discuss and provide comments on IPM assumptions related to six main topics: power system operation, generating resources, emission control technologies, set-up parameters and rule, financial assumptions, and fuel assumptions.

For the summer 2006 set of IPM runs, ICF generated two different parsed files. One file includes all fuel burning units (fossil, biomass, landfill gas), as well as, non-fuel burning units (hydro, wind, etc.). The second file contains just the fossil-fuel burning units (e.g., emissions from biomass and landfill gas are omitted). The RPOs decided to use the fossil-only file for modeling to be consistent with the USEPA, since the USEPA used the fossil only results for CAIR analyses. For the 10 VISTAS states, non-fossil fuels accounted for only 0.13 percent of the $NO_x$ emissions and 0.04 percent of the $SO_2$ emissions in the 2009 IPM runs VISTAS/ASIP asked S/L agencies to review the results of the summer 2006 set of IPM runs, which were incorporated into the VISTAS inventory. The SCDHEC primarily reviewed and commented on the IPM results with respect to IPM decisions on $NO_x$ post-combustion controls and $SO_2$ scrubbers.

### 2. VISTAS/MRPO IPM runs for EGU sources

The following summary of the VISTAS/MRPO IPM® modeling is based on ICF's documentation Future Year Electricity Generating Sector Emission Inventory Development Using the IPM® in Support of Fine Particulate Mass and Visibility Modeling in the VISTAS and Midwest RPO Regions, April 2005. The ICF documentation is to be used as an extension to EPA's proposed CAIR modeling runs documented in Documentation Supplement for EPA Modeling Applications (V.2.1.6) Using the IPM, EPA 430/R-03-007, July 2003.

IPM provides "forecasts of least-cost capacity expansion, electricity dispatch, and emission control strategies for meeting energy demand and environmental, transmission, dispatch, and reliability constraints." The underlying database in this modeling is USEPA's National Electric Energy Data System (NEEDS) released with the CAIR Notice of Data Availability (NODA). The NEEDS database contains the existing and planned/committed unit data in the USEPA modeling applications of IPM. NEEDS includes basic geographic, operating, air emissions, and other data on these generating units. VISTAS States and stakeholders provided changes for:

- $NO_x$ post-combustion control on existing units
- $SO_2$ scrubbers on existing units
- $SO_2$ emission limitations
- PM controls on existing units
- Summer net dependable capacity
- Heat rate for existing units
- $SO_2$ and $NO_x$ control plans based on State rules or enforcement settlements

The years 2009 and 2018 were explicitly modeled in this set of runs.

### 3. Post-Processing of IPM Parsed Files

The following summary of the VISTAS/MRPO IPM modeling is based on Pechan's documentation LADCO IPM Model Parsed File Post-Processing Methodology and File Preparation, February 8, 2005. The essence of the IPM model post-processing methodology is to take an initial IPM model output file and transform it into air quality model input files. ICF via VISTAS/MRPO provided an initial spreadsheet file containing unit-level records of both (1) "existing" units and (2) committed or new generic aggregates.

All records have unit and fuel type data; existing, retrofit (for $SO_2$ and $NO_x$), and separate $NO_x$ control information; annual $SO_2$ and $NO_x$ emissions and heat input; summer season (May-September) $NO_x$ and heat input; July day $NO_x$ and heat input; coal heat input by coal type; nameplate capacity (MW), and State FIPS code. Existing units also have county FIPS code, a unique plant identifier (ORISPL) and unit ID (also called boiler ID) (BLRID); generic units do not have these data. The processing includes estimating various types of emissions and adding in control efficiencies, stack parameters, latitude-longitude coordinates, and State identifiers (plant ID, point ID, stack ID, process ID). Additionally, the generic units are sited in a county and given appropriate IDs. This processing is described in more detail below.

The data are prepared by transforming the generic aggregates into units similar to the existing units in terms of the available data. The generic aggregates are split into smaller generic units based on their unit types and capacity, are provided a dummy ORIS unique plant and boiler ID, and are given a county FIPS code based on an algorithm that sites each generic by assigning a sister plant that is in a county based on its attainment/nonattainment status. Within a State, plants (in county then ORIS plant code order) in attainment counties are used first as sister sites to generic units, followed by plants in PM2.5 nonattainment counties, followed by plants in 8 hour ozone nonattainment counties. Note that no LADCO or VISTAS States provided blackout counties that would not be considered when siting generics, so this process is identical to the one used for the USEPA IPM post-processing.

SCCs were assigned for all units; unit/fuel/firing/bottom type data were used for existing units' assignments, while only unit and fuel type were used for generic units' assignments. Latitude-longitude coordinates were assigned, first using the USEPA-provided data files, secondly using the September 17, 2004 Pechan in-house latitude-longitude file, and lastly using county centroids. These data were only used when the data were not provided in the 2002 NIF files. Stack parameters were attached, first using the USEPA-provided data files, secondly using a March 9, 2004 Pechan in-house stack parameter file based on previous EIA-767 data, and lastly using an USEPA June 2003 SCC-based default stack parameter file. These data were only used when the data were not provided in the 2002 NIF files.

Additional data were required for estimating VOC, CO, filterable primary PM10 and PM2.5, PM condensable, and NH3 emissions for all units. Thus, ash and sulfur contents were assigned by first using 2002 EIA-767 values for existing units or SCC-based defaults; filterable PM10 and PM2.5 efficiencies were obtained from the 2002 EGU NEI that were based on 2002 EIA-767 control data and the PM Calculator program (a default of 99.2 percent is used for coal units if necessary); fuel use was back calculated from the given heat input and a default SCC-based heat content; and emission factors were obtained from an USEPA-approved October 7, 2004 Pechan emission factor file based on AP-42 emission factors. Note that this updated file is not the one used for estimating emissions for previous USEPA post-processed IPM files. Emissions for 28 temporal-pollutant combinations were estimated since there are seven pollutants (VOC, CO, primary PM10 and PM2.5, NH3, $SO_2$ and $NO_x$) and four temporal periods (annual, summer season, winter season, July day).

The next step was to match the IPM unit IDs with the identifiers in VISTAS/ASIP 2002 inventory. A crosswalk file was used to obtain FIPS State and county, plant ID (within State and county), and point ID. If the FIPS State and county, plant ID and point ID are in the 2002 VISTAS NIF tables, then the process ID and stack ID are obtained from the NIF; otherwise, defaults, described above, were used.

Pechan provided the post-processed files in NIF 3.0 format. Two sets of tables were developed:

"NIF files" for IPM units that have a crosswalk match and are in the 2002 VISTAS inventory, and "NoNIF files" for IPM units that are not in the 2002 VISTAS inventory (which includes existing units with or without a crosswalk match as well as generic units).

For the 2009 projections, VISTAS/ASIP states reviewed the PM and NH3 emissions from EGUs as provided by Pechan and identified significantly higher emissions in 2009 than in 2002. It was determined that Pechan used a set of PM and NH3 emission factors that are "the most recent USEPA approved uncontrolled emission factors" for estimating 2009 emissions. These factors are most likely not the same emission factors used by States for estimating these emissions in 2002 for EGUs in the VISTAS/ASIP region. Thus, the emission increase from 2002 to 2009 was simply an artifact of the change in emission factor, not anything to do with changes in activity or control technology application. Also, VISTAS/ASIP states identified an inconsistent use of SCCs for determining emission factors between the base and future years. The resolution of the PM and NH3 problem is fully documented in EGU Emission Factors and Emission Factor Assignment, memorandum from Greg Stella to VISTAS State Point Source Contacts and VISTAS EGU Special Interest Workgroup, June 13, 2005 (attached in Appendix Q). The first step was the adjustment of the 2002 base year emissions inventory. Using the latest "USEPA-approved" uncontrolled emission factors by SCC, Alpine Geophysics utilized CERR or VISTAS/ASIP reported annual heat input, fuel throughput, heat, ash and sulfur content to estimate annual uncontrolled emissions for units identified as output by IPM. This step was conducted for non-CEM pollutants (CO, VOC, PM, and NH3) only. For PM emissions, the condensable component of emissions was calculated and added to the resulting PM primary estimations. The resulting emissions were then adjusted by any control efficiency factors reported in the CERR or VISTAS data collection effort. The second adjustment was to the future year inventories. Alpine Geophysics updated the SCCs in the future year inventory to assign the same base year SCC. Using the same methods as described for the 2002 revisions, those non-IPM generated pollutants were estimated using IPM predicted fuel characteristics and base year 2002 SCC assignments.

### 4. S/L Adjustments to IPM Modeling Results

After the S/L agency review of the final set of IPM runs, S/L agencies specified a number of changes to the IPM results to better reflect current information on when and where future controls would occur. These changes to the IPM results primarily involved S/L agency addition or subtraction of future emission controls based on the best available data from state rules, enforcement agreements, compliance plans, permits, and discussions/commitments from individual companies.

Some S/L agencies specified changes to the controls assigned by IPM to reflect their best estimates of emission controls. The VISTAS/ASIP contractors used a scrubber control efficiency of 90 percent when adding or removing $SO_2$ scrubber controls, used a control efficiency of 90 percent when adding or removing $NO_x$ SCR controls at coal-fired plants, 80 percent when adding or removing $NO_x$ SCR controls at gas-fired plants, and 35 percent when adding or removing $NO_x$ SNCR controls. The specific changes from SCDHEC to the IPM results are also summarized in Table F1-3.

S/L agencies provided information and/or comment on changes in stack parameters from the 2002 inventory for the 2009 inventory. Changes to stack parameters were also made in cases where new controls are scheduled to be installed. In cases where an emission unit projected to have a $SO_2$ scrubber in 2009, some states were able to provide revised stack parameters for some units based on design features for the new control system. Other units projected to install scrubbers by 2009 are not far enough along in the design process to have specific design details. For those units, the VISTAS EGU SIWG made the following assumptions: 1) the scrubber is a wet scrubber; 2) keep the current stack height the same; 3) keep the current flow rate the same, and 4) change the stack exit temperature to 169 degrees F (this is the virtual temperature derived from a wet temperature of 130 degrees F). VISTAS determined that exit temperature (wet) of 130 degrees F +/- 5 degrees F is representative of different size units and wet scrubber technology.

**Table F1-3**
**SCDHEC Adjustments to IPM Results for the 2009 EGU Inventory**

| State | Plant Name and ID | Unit | Nature of Update/Correction |
|---|---|---|---|
| SC | Cross ORISID=130 | 1, 2 | Unit 1: upgrade scrubber from 82 percent to 95 percent removal efficiency by June 30, 2006. Recalculate emissions based on upgrade in control efficiency.<br>Unit 2: upgrade scrubber from 70 percent to 87 percent removal efficiency by June 30, 2006. Recalculate emissions based on upgrade in control efficiency. |
| SC | Winyah ORISID=6249 | 1 – 4 | Unit 1: Install scrubber that meets 95 percent removal efficiency by Dec. 31, 2008; Upgrade ESP from 0.38 to 0.03 lb/mmBTU by Dec. 31, 2008<br>Unit 2: Replace scrubber with one that meets 95 percent removal efficiency from 45 percent by Dec. 31, 2008; Upgrade ESP from 0.10 to 0.03 lb/mmBTU by Dec. 31, 2008<br>Unit 3: Upgrade scrubber from 70 percent to 90 percent removal efficiency by Dec. 31, 2012; Upgrade ESP from 0.10 to 0.03 lb/mmBTU by Dec. 31, 2012<br>Unit 4: Upgrade scrubber from 70 percent to 90 percent removal efficiency by Dec. 31, 2007; Upgrade ESP from 0.10 to 0.03 lb/mmBTU by Dec. 31, 2007<br>Recalculated $SO_2$ and PM emissions based on upgrade in control efficiencies. |
| SC | Dolphus Grainger ORISID=3317 | 1, 2 | Unit 1: Upgrade ESP from 0.60 to 0.03 lb/mmBTU by Dec. 31, 2012. Reduced PM10 and PM25 emissions in 2018 by 95 percent based on change in allowable emission rate<br>Unit 2: Install low $NO_x$ burners that meet 0.46 lb/mmBTU from 0.9 by May 1, 2004. Recalculated $NO_x$ emissions using 0.46/lbs/mmBtu and IPM heat input<br>Unit 2: Upgrade ESP from 0.60 to 0.03 lb/mmBTU by Dec. 31, 2012. Reduced PM10 and PM25 emissions in 2018 by 95 percent based on change in allowable emission rate |
| SC | Jeffries ORISID=3319 | 3, 4 | Unit 3: Upgrade ESP from 0.54 to 0.03 lb/mmBTU by Dec. 31, 2012. Reduced PM10 and PM25 emissions in 2018 by 94.44 percent based on change in allowable emission rate<br>Unit 4: Upgrade ESP from 0.54 to 0.03 lb/mmBTU by Dec. 31, 2012. Reduced PM10 and PM25 emissions in 2018 by 94.44 percent based on change in allowable emission rate |

| | | | |
|---|---|---|---|
| SC | W S Lee<br>ORISID=3264 | 1, 2 | IPM does not indicate that these units are installing SOFA $NO_x$ control technology by April 30, 2006 to meet 0.27 lb/mmBTU, down from 0.45 lb/mmBtu. Calculated $NO_x$ emissions using IPM heat input and 0.27 lbs/mmBtu |
| SC | Generic Unit<br>ORISID=900545 | All | All predictions for generic units appear reasonable with the exception of Plant ID ORIS900545 Point ID GSC45 which was modeled in Georgetown County. It will be very difficult to add new generation this close to the Cape Romain Class I area. Santee Cooper has no plans for future generation in Georgetown County, but does have plans for new future generation in Florence County. This unit was moved to coordinates specified in Florence County. |

### 5. Summary of 2009 EGU Point Source Inventory

Tables F1-4 and F1-5 summarize the 2002 base year inventory and 2009 projection inventory for the EGU source sector. The 2009 inventory include the adjustments to the IPM results specified by the S/L agencies in the previous section.

**Table F1-4**
**EGU Point Source $NO_x$ Emission Comparison for 2002 and 2009.**

| State | 2002 VISTAS | 2009 IPM Based with S/L Adjustments |
|---|---|---|
| AL | 161,038 | 82,305 |
| FL | 257,677 | 86,165 |
| GA | 147,517 | 98,497 |
| KY | 198,817 | 92,021 |
| MS | 43,135 | 36,011 |
| NC | 151,854 | 66,522 |
| SC | 88,241 | 46,915 |
| TN | 157,307 | 66,405 |
| VA | 86,886 | 66,219 |
| WV | 230,977 | 86,328 |
| Total | 1,523,449 | 727,388 |

Note: Emission summaries above are based on SCC's 1-01-xxx-xx and 2-01-xxx-xx .

**Table F1-5**
**EGU Point Source VOC Emission Comparison for 2002 and 2009.**

| State | 2002 VISTAS | 2009 IPM Based with S/L Adjustments |
|---|---|---|
| AL | 2,295 | 2,473 |
| FL | 2,524 | 1,910 |
| GA | 1,244 | 2,314 |

| | | |
|---|---|---|
| KY | 1,487 | 1,369 |
| MS | 648 | 404 |
| NC | 988 | 954 |
| SC | 470 | 660 |
| TN | 926 | 932 |
| VA | 754 | 778 |
| WV | 1,180 | 1,361 |
| Total | 12,516 | 13,155 |

Note: Emission summaries above are based on SCC's 1-01-xxx-xx and 2-01-xxx-xx.

**B. Non-EGU Emission Projections**

The general approach for assembling future year data was to use recently updated growth and control data consistent with the data used in the USEPA's CAIR analyses, supplement these data with available stakeholder input, and provide the results for stakeholder review to ensure credibility. The VISTAS/ASIP contractor used the 2002 VISTAS/ASIP base year inventory, based on the 2002 CERR submittals as the starting point for the non-EGU projection inventory. The 2002 VISTAS/ASIP point source emission inventory contains both EGUs and non-EGUs. Since this file contains both EGUs and nonEGU point sources, and EGU emissions are projected using the IPM, it was necessary to split the 2002 point source file into two components. The first component contains those emission units accounted for in the IPM forecasts. The second component contains all other point sources not accounted for in IPM and constitutes the non-EGU emissions inventory.

MACTEC performed the following activities to apply growth and control factors to the 2002 non-EGU emissions inventory to generate the 2009 projection inventory:

- Obtained, reviewed, and applied the most current growth factors developed by EPA, based on forecasts from an updated Regional Economic Models, Inc. (REMI) model (version 5.5) and the latest Annual Energy Outlook published by the Department of Energy (DOE);

- Obtained, reviewed, and applied any State-specific or sector-specific growth factors submitted by stakeholders;

- Obtained and incorporated information regarding sources that have shut down after 2002 and set the emissions to zero in the projection inventories;

- Obtained, reviewed, and applied control assumptions;

- Provided data files in NIF3.0 format and emission summaries in EXCEL format for review and comment; and

- Updated the database with corrections or new information from S/L agencies based on their review of the 2009 inventory.

The following sections discuss each of these steps.

**1. Growth assumptions for non-EGU sources**

The growth factor data used in developing the emission inventory were consistent with the USEPA's analyses for the CAIR rulemaking. These growth factors are fully documented in the reports entitled

Development of Growth Factors for Future Year Modeling Inventories (dated April 30, 2004) and CAIR Emission Inventory Overview (dated July 23, 2004). Three sources of data were used in developing the growth factors for the 2009 emissions inventory:

- State-specific growth rates from the Regional Economic Model, Inc. (REMI) Policy Insight® model, version 5.5 (being used in the development of the EGAS Version 5.0). The REMI socioeconomic data (output by industry sector, population, farm sector value added, and gasoline and oil expenditures) are available by 4-digit SIC code at the State level.

- Energy consumption data from the DOE's Energy Information Administration's (EIA) Annual Energy Outlook 2004, with Projections through 2025 for use in generating growth factors for non-EGU fuel combustion sources. These data include regional or national fuel-use forecast data that were mapped to specific SCCs for the non-EGU fuel use sectors (e.g., commercial coal, industrial natural gas). Growth factors for the residential natural gas combustion category, for example, are based on residential natural gas consumption forecasts that are reported at the Census division level. These Census divisions represent a group of States (e.g., the South Atlantic division includes eight southeastern States and the District of Columbia). Although one would expect different growth rates in each of these States due to unique demographic and socioeconomic trends, all States within each division received the same growth rate.

- Specific changes for sectors (e.g., plastics, synthetic rubber, carbon black, cement manufacturing, primary metals, fabricated metals, motor vehicles and equipment) where the REMI-based rates were unrealistic or highly uncertain. Growth projections for these sectors were based on industry group forecasts, Bureau of Labor Statistics (BLS) projections and Bureau of Economic Analysis (BEA) historical growth from 1987-2002.

In addition to the growth data described above, VISTAS received two sets of growth projections from stakeholders. The American Forest and Paper Association (AF&PA) supplied growth projections for the pulp and paper sector, which were applied to SIC 26xx Paper and Allied Products, for growth from 2002 to 2009. The AF&PA projection factor (1.067) is for the United States industry and applies to all States equally. The number comes from the 15-year forecast for world pulp and recovered paper prepared by Resource Information Systems Inc. (RISI). The VISTAS/ASIP contractor used the above AF&PA growth factors by SIC instead of the factors obtained from the USEPA's CAIR analysis for the 2009 emission inventory.

For the 2009 inventory, the VISTAS/ASIP contractor made one additional change to the growth factors. The AEO2004 data was replaced with the more recent AEO2006 forecasts (released in February 2006) to reflect changes in the energy market and to improve the emissions growth factors produced. The VISTAS/ASIP contractor obtained the corresponding AEO2006 projection tables from DOE's web site. VISTAS developed tables comparing the growth factors based on AEO2004 and AEO2006 and these comparison tables were reviewed by the S/L agencies. Based on this review, the VISTAS/ASIP states decided to use the AEO2006 growth factors for fuel burning SCCs.

VISTAS used the USEPA's EGAS model and updated the corresponding AEO2006 projection tables to create growth factors by SCC. VISTAS applied the updated growth factors to 2002 actual emissions and replaced the 2009 emissions in NIF EM tables for the affected SCCs.

### 2. Control Programs applied to non-EGU sources

VISTAS developed two control scenarios: on-the-books (OTB) controls and on-the-way (OTW) controls. The OTB control scenario accounts for post-2002 emission reductions from recently promulgated federal, State, local, and site-specific control programs. The OTW control scenario accounts for proposed (but not final) control programs that are reasonably anticipated to result in post-2002 emission reductions. The methodologies used to account for the emission reductions associated with these emission control programs are discussed in the following sections.

**Table F1-6**
**Non-EGU Point Source Control Programs Included in 2009 Inventory.**

| |
|---|
| On-the-Books (Cut-off of July 1, 2004 for Base 1 adoption) |
| |
| • Atlanta / Northern Kentucky / Birmingham 1-hr SIPs |
| • Industrial Boiler/Process Heater/RICE MACT |
| • $NO_x$ RACT in 1-hr NAA SIPs |
| • $NO_x$ SIP Call (Phase I- except where States have adopted II already e.g. NC) |
| • RFP 3 percent Plans where in place for one hour plans |
| • VOC 2-, 4-, 7-, and 10-year MACT Standards |
| • Combustion Turbine MACT |
| |
| On-the-Way |
| |
| • $NO_x$ SIP Call (Phase II – remaining States & IC engines) |

**a. OTB - $NO_x$ SIP Call (Phase I)**

Phase I of the $NO_x$ SIP call applies to certain large non-EGUs, including large industrial boilers and turbines, and cement kilns. States in the VISTAS region affected by the $NO_x$ SIP call have developed rules for the control of $NO_x$ emissions that have been approved by the USEPA. VISTAS reviewed the available State rules and guidance documents to determine the affected sources and ozone season allowances. VISTAS also obtained and reviewed information in the EPA's CAMD $NO_x$ Allowance Tracking System - Allowances Held Report. Since these controls are to be in effect by the year 2007, VISTAS capped the emissions for $NO_x$ SIP call affected sources at 2007 levels and carried forward the capped levels for the 2009 future year inventory.

**b. OTB - Industrial Boiler/Process Heater MACT**

The USEPA anticipates reductions in PM and $SO_2$ as a result of the Industrial Boiler/Process Heater MACT standard. The methods used to account for these reductions are the same as those used for the CAIR analysis. Reductions were included for existing units firing solid fuel (coal, wood, waste, biomass), which had a design capacity greater than 10 mmBtu/hr. The USEPA prepared a list of SCCs for solid fuel industrial, commercial/ institutional boilers and process heaters. The VISTAS/ASIP contractor identified boilers greater than 10 mmBtu/hr using either the boiler capacity from the VISTAS 2002 inventory or if the boiler capacity was missing, a default capacity based on a methodology developed by the USEPA for assigning default capacities based on SCC code. The applied MACT control efficiencies were 4 percent for $SO_2$ and 40 for percent for PM10 and PM2.5.

**c. OTB - 2, 4, 7, and 10-year MACT Standards**

Maximum achievable control technology (MACT) requirements were also applied, as documented in the report entitled Control Packet Development and Data Sources, dated July 14, 2004. The point source MACTs and associated emission reductions were designed from Federal Register (FR) notices and discussions with the USEPA's Emission Standards Division (ESD) staff. VISTAS did not apply reductions for MACT standards with an initial compliance date of 2001 or earlier, assuming that the effects of these controls are already accounted for in the 2002 inventories supplied by the States. Emission reductions were applied only for MACT standards with an initial compliance date of 2002 or greater.

#### d. OTB Combustion Turbine MACT

The projection inventory does not include the $NO_x$ co-benefit effects of the MACT regulations for Gas Turbines or stationary Reciprocating Internal Combustion Engines, which the USEPA estimates to be small compared to the overall inventory.

#### e. OTW - $NO_x$ SIP Call (Phase II)

The final Phase II $NO_x$ SIP call rule was finalized on April 21, 2004. States had until April 21, 2005, to submit SIPs meeting the Phase II $NO_x$ budget requirements. The Phase II rule applies to large IC engines, which are primarily used in pipeline transmission service at compressor stations. VISTAS identified affected units using the same methodology as was used by the USEPA in the proposed Phase II rule (i.e., a large IC engine is one that emitted, on average, more than 1 ton per day during 2002). The final rule reflects a control level of 82 percent for natural gas-fired IC engines and 90 percent for diesel or dual fuel categories. North Carolina provided more specific information on the anticipated controls at the compressor stations. This information was used in the 2009 inventory instead of the default approach used by the USEPA in the proposed Phase II rule.

#### f. Clean Air Interstate Rule

CAIR does not require or assume additional emission reductions from non-EGU boilers and turbines.

### 3. Summary of 2009 non-EGU Point Source Inventory

Tables F1-7 and F1-8 summarize the 2009 non-EGU point source inventory for $NO_x$ and VOC emissions.

**Table F1-7**
**Non-EGU Point Source $NO_x$ Emission Comparison for 2002 & 2009.**

| State | 2002 | 2009 |
|---|---|---|
| AL | 83,310 | 69,409 |
| FL | 45,156 | 46,020 |
| GA | 49,251 | 50,353 |
| KY | 38,392 | 37,758 |
| MS | 61,526 | 56,397 |
| NC | 44,928 | 34,767 |
| SC | 42,153 | 40,019 |
| TN | 64,344 | 57,883 |
| VA | 60,415 | 51,046 |

| | | |
|---|---|---|
| WV | 46,612 | 38,031 |
| Total | 536,087 | 481,683 |

**Table F1-8**
**Non-EGU Point Source VOC Emission Comparison for 2002 & 2009.**

| State | 2002 | 2009 |
|---|---|---|
| AL | 47,037 | 46,644 |
| FL | 38,471 | 36,880 |
| GA | 33,709 | 34,116 |
| KY | 44,834 | 47,785 |
| MS | 43,204 | 37,747 |
| NC | 61,182 | 61,925 |
| SC | 38,458 | 35,665 |
| TN | 84,328 | 74,089 |
| VA | 43,152 | 43,726 |
| WV | 14,595 | 13,810 |
| Total | 448,970 | 432,387 |